WHITING PETROLEUM CORP
Form 10-Q
July 31, 2014
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2014

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______________ to _______________

Commission file number: 001 31899

WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20 0098515 (I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 Denver, Colorado (Address of principal executive offices)	 80290 2300 (Zip code)

(303) 837 1661
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

Number of shares of the registrant's common stock outstanding at July 15, 2014: 118,981,965 shares.

TABLE OF CONTENTS

Table of Contents

Glossary of Certain Definitions

Unless the context otherwise requires, the terms “we,” “us,” “our” or “ours” when used in this Quarterly Report on Form 10-Q refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this report:

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

“Bcf” One billion cubic feet, used in reference to natural gas or CO2.

“BOE” One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

“CO2” Carbon dioxide.

“CO2 flood” A tertiary recovery method in which CO2 is injected into a reservoir to enhance hydrocarbon recovery.

“completion” The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“costless collar” An options position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception.

“development well” A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“differential” The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead price received.

“EOR” Enhanced oil recovery.

“exploratory well” A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

“FASB” Financial Accounting Standards Board.

“FASB ASC” The Financial Accounting Standards Board Accounting Standards Codification.

“field” An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

“GAAP” Generally accepted accounting principles in the United States of America.

“gross acres or wells” The total acres or wells, as the case may be, in which a working interest is owned.

“ISDA” International Swaps and Derivatives Association, Inc.

“lease operating expense” or “LOE” The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

“LIBOR” London interbank offered rate.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBbl/d” One MBbl per day.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet, used in reference to natural gas or CO2.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet, used in reference to natural gas or CO2.

“MMcf/d” One MMcf per day.

“net production” The total production attributable to our fractional working interest owned.

“NGL” Natural gas liquid.

“NYMEX” The New York Mercantile Exchange.

“plug-and-perf technology” A horizontal well completion technique in which hydraulic fractures are performed in multiple stages, with each stage utilizing a bridge plug to divert fracture stimulation fluids through the casing perforations into the formation within that stage.

“plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

“proved reserves” Those reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and
b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

2

Table of Contents

“proved undeveloped reserves” Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

“reserves” Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“royalty” The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

“royalty interest” An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

“SEC” The United States Securities and Exchange Commission.

“working interest” The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

“workover” Operations on a producing well to restore or increase production.

Table of Contents

PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

WHITING PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (unaudited)

(in thousands, except share and per share data)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 227,083	$ 699,460
Accounts receivable trade, net	464,474	341,177
Prepaid expenses and other	41,566	28,981
Total current assets	733,123	1,069,618
Property and equipment:		
Oil and gas properties, successful efforts method	11,421,570	10,065,150
Other property and equipment	234,116	206,385
Total property and equipment	11,655,686	10,271,535
Less accumulated depreciation, depletion and amortization	(3,158,917)	(2,676,490)
Total property and equipment, net	8,496,769	7,595,045
Debt issuance costs	47,845	48,530
Other long-term assets	81,231	120,277
TOTAL ASSETS	$ 9,358,968	$ 8,833,470
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 144,801	$ 107,692
Accrued capital expenditures	216,076	158,739
Accrued liabilities and other	219,525	214,109
Revenues and royalties payable	214,147	198,558
Taxes payable	69,505	50,052
Accrued interest	43,057	44,405
Derivative liabilities	24,044	3,482
Deferred income taxes	10,324	648
Total current liabilities	941,479	777,685

Long-term debt	2,653,512	2,653,834
Deferred income taxes	1,436,447	1,278,030
Production Participation Plan liability	-	87,503
Asset retirement obligations	157,243	116,442
Deferred gain on sale	68,852	79,065
Other long-term liabilities	4,300	4,212
Total liabilities	5,261,833	4,996,771
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 300,000,000 shares authorized; 120,443,221 issued and 118,981,965 outstanding as of June 30, 2014 and 120,101,555 issued and 118,657,245 outstanding as of December 31, 2013	120	120
Additional paid-in capital	1,583,501	1,583,542
Retained earnings	2,505,418	2,244,905
Total Whiting shareholders' equity	4,089,039	3,828,567
Noncontrolling interest	8,096	8,132
Total equity	4,097,135	3,836,699
TOTAL LIABILITIES AND EQUITY	$ 9,358,968	$ 8,833,470

See notes to consolidated financial statements.

4

Table of Contents

WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF INCOME (unaudited)

(in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
REVENUES AND OTHER INCOME:				
Oil, NGL and natural gas sales	$ 825,760	$ 651,868	$ 1,547,010	$ 1,256,982
Loss on hedging activities	-	(437)	-	(648)
Amortization of deferred gain on sale	7,473	7,954	15,217	15,930
Gain on sale of properties	1,796	3,387	12,355	3,432
Interest income and other	593	797	1,289	1,244
Total revenues and other income	835,622	663,569	1,575,871	1,276,940
COSTS AND EXPENSES:				
Lease operating	118,361	105,080	233,147	204,958
Production taxes	68,857	53,814	128,887	105,085
Depreciation, depletion and amortization	268,509	223,446	503,774	424,605
Exploration and impairment	31,512	43,393	73,619	80,673
General and administrative	35,555	29,213	67,889	58,098
Interest expense	39,045	23,121	81,189	44,591
Change in Production Participation Plan liability	(3,636)	7,723	-	12,130
Commodity derivative (gain) loss, net	26,076	(30,192)	50,611	1,065
Total costs and expenses	584,279	455,598	1,139,116	931,205
INCOME BEFORE INCOME TAXES	251,343	207,971	436,755	345,735
INCOME TAX EXPENSE (BENEFIT):				
Current	7,355	(2,511)	8,355	(2,089)
Deferred	92,562	75,538	167,923	126,636
Income tax expense	99,917	73,027	176,278	124,547
NET INCOME	151,426	134,944	260,477	221,188
Net loss attributable to noncontrolling interests	18	12	36	31
NET INCOME AVAILABLE TO SHAREHOLDERS	151,444	134,956	260,513	221,219
Preferred stock dividends	-	(269)	-	(538)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 151,444	$ 134,687	$ 260,513	$ 220,681
EARNINGS PER COMMON SHARE:				
Basic	$ 1.27	$ 1.14	$ 2.19	$ 1.87
Diluted	$ 1.26	$ 1.14	$ 2.17	$ 1.86
WEIGHTED AVERAGE SHARES OUTSTANDING:				

Basic	118,968	117,930	118,946	117,859
Diluted	120,027	118,901	120,045	118,929

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)

(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NET INCOME	$ 151,426	$ 134,944	$ 260,477	$ 221,188
OTHER COMPREHENSIVE INCOME, NET OF TAX:				
OCI amortization on de-designated hedges (1) (2)	-	277	-	410
Total other comprehensive income, net of tax	-	277	-	410
COMPREHENSIVE INCOME	151,426	135,221	260,477	221,598
Comprehensive loss attributable to noncontrolling interest	18	12	36	31
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$ 151,444	$ 135,233	$ 260,513	$ 221,629

(1) Presented net of income tax expense of $160 and $238 for the three and six months ended June 30, 2013, respectively.
(2) These OCI amortization amounts on de-designated hedges are reclassified from accumulated other comprehensive income ("AOCI") to loss on hedging activities in the consolidated statements of income.

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 260,477	$ 221,188
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	503,774	424,605
Deferred income tax expense	167,923	126,636
Amortization of debt issuance costs and debt premium	7,342	4,950
Stock-based compensation	11,046	11,632
Amortization of deferred gain on sale	(15,217)	(15,930)
Gain on sale of properties	(12,355)	(3,432)
Undeveloped leasehold and oil and gas property impairments	36,031	37,464
Exploratory dry hole costs	3,622	11,628
Change in Production Participation Plan liability	-	12,130
Non-cash portion of derivative (gains) losses	44,744	(10,614)
Other, net	(3,205)	(9,359)
Changes in current assets and liabilities:		
Accounts receivable trade, net	(123,297)	(27,527)
Prepaid expense and other	(13,633)	(10,738)
Accounts payable trade and accrued liabilities	(10,628)	(54,980)
Revenues and royalties payable	15,589	11,084
Taxes payable	19,453	11,494
Net cash provided by operating activities	891,666	740,231
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and development capital expenditures	(1,326,080)	(1,109,852)
Acquisition of oil and gas properties	(44,519)	(91,620)
Other property and equipment	(34,675)	(38,183)
Proceeds from sale of oil and gas properties	83,152	3,127
Deposit received on properties held for sale	-	85,980
Issuance of note receivable	-	(10,004)
Cash paid for investing derivatives	-	(44,900)
Cash settlements received on investing derivatives	-	2,371
Net cash used in investing activities	(1,322,122)	(1,203,081)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit agreement	100,000	1,300,000

Repayments of borrowings under credit agreement	(100,000)	(850,000)
Debt issuance costs	(4,461)	(2,586)
Proceeds from stock options exercised	253	-
Restricted stock used for tax withholdings	(11,340)	(5,514)
Repayment of tax sharing liability	(26,373)	-
Preferred stock dividends paid	-	(538)
Net cash provided by (used in) financing activities	(41,921)	441,362
NET CHANGE IN CASH AND CASH EQUIVALENTS	(472,377)	(21,488)
CASH AND CASH EQUIVALENTS:		
Beginning of period	699,460	44,800
End of period	$ 227,083	$ 23,312
NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 216,076	$ 109,744

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF EQUITY (unaudited)

(in thousands)

	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equ
BALANCES-January 1, 2013	172	$ -	118,582	$ 119	$ 1,566,717	$ (1,236)	$ 1,879,388	$ 3,444,988	$ 8,184	$ 3,
Net income (loss)	-	-	-	-	-	-	221,219	221,219	(31)	22
Other comprehensive income	-	-	-	-	-	410	-	410	-	41
Conversion of preferred stock to common	(172)	-	794	1	-	-	-	1	-	1
Restricted stock issued	-	-	941	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(69)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(114)	-	(5,514)	-	-	(5,514)	-	(5
Stock-based compensation	-	-	-	-	11,632	-	-	11,632	-	11
Preferred dividends paid	-	-	-	-	-	-	(538)	(538)	-	(5
BALANCES-June 30, 2013	-	$ -	120,134	$ 120	$ 1,572,835	$ (826)	$ 2,100,069	$ 3,672,198	$ 8,153	$ 3,
BALANCES-January 1, 2014	-	$ -	120,102	$ 120	$ 1,583,542	$ -	$ 2,244,905	$ 3,828,567	$ 8,132	$ 3,
Net income (loss)	-	-	-	-	-	-	260,513	260,513	(36)	26
Exercise of stock options	-	-	5	-	253	-	-	253	-	25
Restricted stock issued	-	-	908	1	(1)	-	-	-	-	-

Restricted stock forfeited	-	-	(381)	(1)	1	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(191)	-	(11,340)	-	-	(11,340)	-	(1
Stock-based compensation	-	-	-	-	11,046	-	-	11,046	-	1
BALANCES-June 30, 2014	-	$ -	120,443	$ 120	$ 1,583,501	$ -	$ 2,505,418	$ 4,089,039	$ 8,096	$ 4,

See notes to consolidated financial statements.

8

Table of Contents

WHITING PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that explores for, develops, acquires and produces crude oil, NGLs and natural gas primarily in the Rocky Mountains and Permian Basin regions of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to "Whiting" or the "Company" are to Whiting Petroleum Corporation and its consolidated subsidiaries.

Consolidated Financial Statements—The unaudited consolidated financial statements include the accounts of Whiting Petroleum Corporation, its consolidated subsidiaries and Whiting's pro rata share of the accounts of Whiting USA Trust I ("Trust I") pursuant to Whiting's 15.8% ownership interest in Trust I. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company's equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation. These financial statements have been prepared in accordance with GAAP for interim financial reporting. In the opinion of management, the accompanying financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim results. However, operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year. Whiting's 2013 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Quarterly Report on Form 10 Q. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in Whiting's 2013 Annual Report on Form 10 K.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method, as well as convertible perpetual preferred stock using the if-converted method. In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of unvested restricted shares or the assumed exercise of stock options (i.e. hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury share method to the extent that such excess tax benefits are more likely than not to be realized. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company's oil and gas producing activities at June 30, 2014 and December 31, 2013 are as follows (in thousands):

	June 30, 2014	December 31, 2013
Proved leasehold costs	$ 1,711,398	$ 1,633,495
Unproved leasehold costs	326,314	372,298
Costs of completed wells and facilities	8,906,004	7,563,350
Wells and facilities in progress	477,854	496,007
Total oil and gas properties, successful efforts method	11,421,570	10,065,150
Accumulated depletion	(3,124,901)	(2,645,841)
Oil and gas properties, net	$ 8,296,669	$ 7,419,309

3. ACQUISITIONS AND DIVESTITURES

2014 Acquisitions

There were no significant acquisitions during the six months ended June 30, 2014.

2014 Divestitures

On March 27, 2014, the Company completed the sale of approximately 49,900 gross (41,000 net) acres, which consisted mainly of undeveloped acreage as well as its interests in certain producing oil and gas wells, in its Big Tex prospect located in the Delaware Basin of Texas for a cash purchase price of $75.6 million (subject to post-closing adjustments) resulting in a pre-tax gain on sale of $12.4 million.

2013 Acquisitions

On September 20, 2013, the Company completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin located in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of $260.0 million. Revenue and earnings from these properties since the September 20, 2013 acquisition date are not material. Disclosures of pro forma revenues and net income for the acquisition of these wells are therefore not material and have not been presented accordingly.

The acquisition was recorded using the purchase method of accounting. The initial purchase price has been adjusted for post-closing settlements that have occurred since the acquisition date totaling $5.8 million. The following table summarizes the allocation of the $255.5 million adjusted purchase price to the tangible assets acquired and liabilities assumed in this acquisition of oil and gas properties (in thousands):

Purchase price	$ 255,537
Allocation of purchase price:	
Proved properties	$ 229,002
Unproved properties	27,335
Oil in tank inventory	522
Accounts receivable	578
Asset retirement obligations	(1,900)
Total	$ 255,537

2013 Divestitures

On October 31, 2013, the Company completed the sale of approximately 45,000 gross (32,200 net) acres, which consisted mainly of undeveloped acreage as well as its interests in certain producing oil and gas wells, in its Big Tex prospect located in the Delaware Basin of Texas for a cash purchase price of $150.8 million, resulting in a pre-tax gain on sale of $11.5 million. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas.

On July 15, 2013, the Company completed the sale of its interests in certain oil and gas producing properties located in its EOR projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, its entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the “Postle Properties”) for a cash purchase price of $809.2 million after selling costs and post-closing adjustments. This divestiture resulted in a pre-tax gain on sale of $109.1 million. The Company used the net proceeds from this sale to repay a portion of the debt outstanding under its credit agreement.

4. LONG-TERM DEBT

Long-term debt consisted of the following at June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013
6.5% Senior Subordinated Notes due 2018	$ 350,000	$ 350,000
5% Senior Notes due 2019	1,100,000	1,100,000
5.75% Senior Notes due 2021, including unamortized debt premium of $3,512 and $3,834, respectively	1,203,512	1,203,834
Total debt	$ 2,653,512	$ 2,653,834

Credit Agreement—Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), the Company's wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of June 30, 2014 had a borrowing base of $2.8 billion, of which $1.2 billion has been

10

committed by lenders and is available for borrowing. The Company may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.8 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of June 30, 2014, the Company had $1,197.0 million of available borrowing capacity, which was net of $3.0 million in letters of credit with no borrowings outstanding.

The credit agreement provides for interest only payments until the expiration date of the agreement, when all outstanding borrowings are due. In April 2014, Whiting Oil and Gas entered into an amendment to its credit agreement that extended the principal repayment date from April 2016 to the earlier of (i) April 2, 2019 or (ii) with certain exceptions, the date that is 91 days prior to the scheduled maturity of any permitted additional unsecured senior or senior subordinated notes, which includes the Company's 5% Senior Notes due March 2019, unless redeemed earlier in accordance with the credit agreement.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of June 30, 2014, $47.0 million was available for additional letters of credit under the agreement.

Interest accrues at the Company's option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, the Company also incurs commitment fees as set forth in the table below on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base, and which are included as a component of interest expense.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. Except for limited exceptions, the credit agreement also restricts the Company's ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the net assets of Whiting Oil and Gas. As of June 30, 2014, total restricted net assets were $4,508.9 million, and the amount of retained earnings free from restrictions was $24.1 million. The credit agreement requires the Company, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. The

Company was in compliance with its covenants under the credit agreement as of June 30, 2014.

The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. The Company has guaranteed the obligations of Whiting Oil and Gas under the credit agreement and has pledged the stock of Whiting Oil and Gas as security for its guarantee.

Senior Notes and Senior Subordinated Notes—In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018 (the "2018 Notes"). The estimated fair value of these notes was $364.9 million as of June 30, 2014, based on quoted market prices for these debt securities, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

Issuance of Senior Notes. In September 2013, the Company issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021 (collectively, the "Senior Notes"). The estimated fair values of the 2019 notes and the 2021 notes were $1,156.4 million and $1,317.0 million, respectively, as of June 30, 2014, based on quoted market prices for these debt securities, and such fair values are therefore designated as Level 1 within the valuation hierarchy.

Table of Contents

The Senior Notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's secured indebtedness, which consists of Whiting Oil and Gas' credit agreement. The 2018 Notes are also unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of the Senior Notes and Whiting Oil and Gas' credit agreement. The Company's obligations under the 2018 Notes and the Senior Notes are fully and unconditionally guaranteed by the Company's 100%-owned subsidiary, Whiting Oil and Gas (the "Guarantor"). Any subsidiaries other than the Guarantor are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S X of the SEC. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in its consolidated subsidiaries.

5. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The Company follows FASB ASC Topic 410, Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The current portions at June 30, 2014 and December 31, 2013 were $8.3 million and $9.7 million, respectively, and are included in accrued liabilities and other. Revisions to the liability typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells. The following table provides a reconciliation of the Company's asset retirement obligations for the six months ended June 30, 2014 (in thousands):

	June 30, 2014
Asset retirement obligation at January 1, 2014	$ 126,148
Additional liability incurred	11,570
Revisions in estimated cash flows (1)	26,215
Accretion expense	6,543
Obligations on sold properties	(759)
Liabilities settled	(4,162)
Asset retirement obligation at June 30, 2014	$ 165,555

(1) Revisions in estimated cash flows during the six months ended June 30, 2014 are primarily attributable to increased estimates of future costs for oilfield services and related materials required to plug and abandon wells in certain fields in the Rocky Mountains region.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and Whiting uses derivative instruments to manage its commodity price risk. Whiting follows FASB ASC Topic 815, Derivatives and Hedging, to account for its derivative financial instruments.

Commodity Derivative Contracts—Historically, prices received for crude oil and natural gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Whiting enters into derivative contracts, primarily costless collars and swaps, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility. Commodity derivative contracts are thereby used to ensure adequate cash flow to fund the Company’s capital programs and to manage returns on acquisitions and drilling programs. Costless collars are designed to establish floor and ceiling prices on anticipated future oil or gas production, while swaps are designed to establish a fixed price for anticipated future oil or gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative contracts for speculative or trading purposes.

Whiting Derivatives. The table below details the Company’s costless collar derivatives, including its proportionate share of Whiting USA Trust II (“Trust II”) derivatives, entered into to hedge forecasted crude oil production revenues, as of July 1, 2014.

Table of Contents

Whiting Petroleum Corporation

Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Jul - Dec 2014	24,090	$ 80.00 - $122.50
Three-way collars (1)	Jul - Dec 2014	8,880,000	$71.82 - $85.68 - $103.85
	Jan - Dec 2015	1,200,000	$70.00 - $85.00 - $107.90
	Total	10,104,090	

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) Whiting will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

In March 2013, Whiting entered into certain crude oil swap contracts in order to achieve more predictable cash flows and manage returns on certain oil and gas properties that the Company was considering for monetization. Accordingly, the acquisition of these swap contracts and cash receipts from settlements of these swap positions have been reflected as an investing activity in the statement of cash flows. On July 15, 2013, upon closing of the sale of the Postle Properties discussed in the Acquisitions and Divestitures footnote, these crude oil swaps were novated to the buyer. Cash settlements that do not relate to investing derivatives or that do not have a significant financing element are reflected as operating activities in the statement of cash flows.

Derivatives Conveyed to Whiting USA Trust II. In connection with the Company’s conveyance in March 2012 of a term net profits interest to Trust II and related sale of 18,400,000 Trust II units to the public, the right to any future hedge payments made or received by Whiting on certain of its derivative contracts have been conveyed to Trust II, and therefore such payments will be included in Trust II’s calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties, which results in third-party public holders of Trust II units receiving 90%, and Whiting retaining 10%, of the future economic results of commodity derivative contracts conveyed to Trust II. The relative ownership of the future economic results of such commodity derivatives is reflected in the tables below. No additional hedges are allowed to be placed on Trust II assets.

The 10% portion of Trust II derivatives that Whiting has retained the economic rights to (and which are also included in the first derivative table above) are as follows:

Whiting Petroleum Corporation

Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Jul - Dec 2014	24,090	$ 80.00 - $122.50

The 90% portion of Trust II derivative contracts of which Whiting has transferred the economic rights to third-party public holders of Trust II units (and which have not been reflected in the above tables) are as follows:

		Third-party Public Holders of Trust II Units	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Jul - Dec 2014	216,810	$ 80.00 - $122.50

Embedded Commodity Derivative Contract—In May 2011, Whiting entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in its EOR project that is being carried out at its North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices. The Company has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and the Company has therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. As of June 30, 2014, the estimated fair value of the embedded derivative in this CO2 purchase contract was an asset of $13.3 million.

Although CO2 is not a commodity that is actively traded on a public exchange, the market price for CO2 generally fluctuates in tandem with increases or decreases in crude oil prices. When Whiting enters into a long-term CO2 purchase contract where the price of CO2 is fixed and does not adjust with changes in oil prices, the Company is exposed to the risk of paying higher than the market rate for CO2 in a climate of declining oil and CO2 prices. This in turn could have a negative impact on the project economics of the Company’s CO2 flood at North Ward Estes. As a result, the Company reduces its exposure to this risk by entering into certain CO2 purchase contracts which have prices that fluctuate along with changes in crude oil prices.

Table of Contents

Derivative Instrument Reporting—All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion. The following tables summarize the effects of commodity derivative instruments on the consolidated statements of income for the three and six months ended June 30, 2014 and 2013 (in thousands):

ASC 815 Cash Flow Hedging Relationships (1)	Income Statement Classification	Loss Reclassified from AOCI into Income (Effective Portion) Six Months Ended June 30, 2014	2013
Commodity contracts	Loss on hedging activities	$ -	$ (648)

ASC 815 Cash Flow Hedging Relationships (1)	Income Statement Classification	Loss Reclassified from AOCI into Income (Effective Portion) Three Months Ended June 30, 2014	2013
Commodity contracts	Loss on hedging activities	$ -	$ (437)

(1) Effective April 1, 2009, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. As a

result, such mark-to-market values at March 31, 2009 were frozen in AOCI as of the de-designation date and were being reclassified into earnings as the original hedged transactions affected income. As of December 31, 2013, all amounts previously in AOCI had been reclassified into earnings.

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Six Months Ended June 30, 2014	2013
Commodity contracts	Commodity derivative (gain) loss, net	$ 27,491	$ 10,406
Embedded commodity contracts	Commodity derivative (gain) loss, net	23,120	(9,341)
Total		$ 50,611	$ 1,065

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Three Months Ended June 30, 2014	2013
Commodity contracts	Commodity derivative (gain) loss, net	$ 17,304	$ (23,854)
Embedded commodity contracts	Commodity derivative (gain) loss, net	8,772	(6,338)
Total		$ 26,076	$ (30,192)

Offsetting of Derivative Assets and Liabilities. With each individual derivative counterparty, the Company typically has numerous hedge positions that span a several-month time period and that typically result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability amount at the end of each reporting period. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets (in thousands):

Table of Contents

Not Designated as ASC 815 Hedges	Balance Sheet Classification	June 30, 2014 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 2,000	$ (1,980)	$ 20
Embedded commodity contracts	Prepaid expenses and other	447	-	447
Commodity contracts	Other long-term assets	1,521	(1,329)	192
Embedded commodity contracts	Other long-term assets	12,849	-	12,849
Total derivative assets		$ 16,817	$ (3,309)	$ 13,508
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 26,024	$ (1,980)	$ 24,044
Commodity contracts	Non-current derivative liabilities	1,329	(1,329)	-
Total derivative liabilities		$ 27,353	$ (3,309)	$ 24,044

Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2013 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 23,752	$ (22,478)	$ 1,274
Embedded commodity contracts	Other long-term assets	36,416	-	36,416
Total derivative assets		$ 60,168	$ (22,478)	$ 37,690
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 25,960	$ (22,478)	$ 3,482
Total derivative liabilities		$ 25,960	$ (22,478)	$ 3,482

(1) Because counterparties to the Company’s derivative contracts are lenders under Whiting Oil and Gas’ credit agreement, which eliminates its need to post or receive collateral associated with its derivative positions, columns for cash collateral pledged or received have not been presented in the tables above.

Contingent Features in Derivative Instruments. None of the Company’s derivative instruments contain credit-risk-related contingent features. Counterparties to the Company’s derivative contracts are high credit-quality financial institutions that are lenders under Whiting’s credit agreement. The Company uses only credit agreement participants to hedge with, since these institutions are secured equally with the holders of Whiting’s bank debt, which eliminates the potential need to post collateral when Whiting is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

7. FAIR VALUE MEASUREMENTS

Cash and cash equivalents, accounts receivable and accounts payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Company's credit agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates. The Company's Senior Notes and Senior Subordinated Notes are recorded at cost, and the fair values of these instruments are included in the Long-Term Debt footnote. The Company's derivative financial instruments are recorded at fair value and include a measure of the Company's own nonperformance risk or that of its counterparties as appropriate.

The Company follows FASB ASC Topic 820, Fair Value Measurement and Disclosure, which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

Table of Contents

- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level.

The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2014 and December 31, 2013, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value June 30, 2014
Financial Assets				
Commodity derivatives – current	$ -	$ 20	$ -	$ 20
Embedded commodity derivatives – current	-	-	447	447
Commodity derivatives – non-current	-	192	-	192
Embedded commodity derivatives – non-current	-	-	12,849	12,849
Total financial assets	$ -	$ 212	$ 13,296	$ 13,508
Financial Liabilities				
Commodity derivatives – current	$ -	$ 24,044	$ -	$ 24,044
Total financial liabilities	$ -	$ 24,044	$ -	$ 24,044

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2013
Financial Assets				
Commodity derivatives – current	$ -	$ 1,274	$ -	$ 1,274
Embedded commodity derivatives – non-current	-	-	36,416	36,416
Total financial assets	$ -	$ 1,274	$ 36,416	$ 37,690
Financial Liabilities				
Commodity derivatives – current	$ -	$ 3,482	$ -	$ 3,482
Total financial liabilities	$ -	$ 3,482	$ -	$ 3,482

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the tables above:

Commodity Derivatives. Commodity derivative instruments consist mainly of costless collar option contracts for crude oil. The Company's costless collars are valued based on an income approach. The option model considers various assumptions, such as quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company's or the counterparty's nonperformance risk, as appropriate. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

Embedded Commodity Derivatives. The embedded commodity derivative relates to a long-term CO_2 purchase contract, which has a price adjustment clause that is linked to changes in NYMEX crude oil prices. Whiting has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to its corresponding host contract, and the Company has therefore bifurcated this embedded pricing feature from the host contract and reflected it at fair value in its consolidated financial statements. This embedded commodity derivative is valued based on an income approach. The option model used in the valuation considers various assumptions, including quoted forward prices for commodities, LIBOR discount rates and either the Company's or the counterparty's nonperformance risk, as appropriate.

Table of Contents

The assumptions used in the CO_2 contract valuation include inputs that are both observable in the marketplace as well as unobservable during the term of the contract. With respect to forward prices for NYMEX crude oil where there is a lack of price transparency in certain future periods, such unobservable oil price inputs are significant to the CO_2 contract valuation methodology, and the contract's fair value is therefore designated as Level 3 within the valuation hierarchy.

Level 3 Fair Value Measurements. A third-party valuation specialist is utilized on a quarterly basis to determine the fair value of the embedded commodity derivative instrument designated as Level 3. The Company reviews this valuation (including the related model inputs and assumptions) and analyzes changes in fair value measurements between periods. The Company corroborates such inputs, calculations and fair value changes using various methodologies, and reviews unobservable inputs for reasonableness utilizing relevant information from other published sources.

The following table presents a reconciliation of changes in the fair value of financial assets (liabilities) designated as Level 3 in the valuation hierarchy for the three and six months ended June 30, 2014 and 2013 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Fair value asset, beginning of period	$ 22,068	$ 26,718	$ 36,416	$ 23,715
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings (1)	(8,772)	6,290	(23,120)	9,293
Transfers into (out of) Level 3	-	-	-	-
Fair value asset, end of period	$ 13,296	$ 33,008	$ 13,296	$ 33,008

(1) Included in commodity derivative (gain) loss, net in the consolidated statements of income.

Quantitative Information About Level 3 Fair Value Measurements. The significant unobservable inputs used in the fair value measurement of the Company's embedded commodity derivative contract designated as Level 3 are as follows:

	Fair Value at June 30, 2014 (in thousands)	Valuation Technique	Unobservable Input	Range (per Bbl)
Embedded commodity derivative	$13,296	Option model	Future prices of NYMEX crude oil after December 31, 2020	$89.78 - $109.47

Sensitivity to Changes In Significant Unobservable Inputs. As presented in the table above, the significant unobservable inputs used in the fair value measurement of Whiting's embedded commodity derivative within its CO_2 purchase contract are the future prices of NYMEX crude oil from January 2021 to December 2029. Significant increases (decreases) in these unobservable inputs in isolation would result in a significantly lower (higher) fair value asset measurement.

Nonrecurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including proved oil and gas property impairments. The Company did not recognize any impairment write-downs with respect to its proved oil and gas properties during the 2014 or 2013 reporting periods presented.

8. DEFERRED COMPENSATION

Production Participation Plan—The Company had a Production Participation Plan (the “Plan”) in which all employees participated. On June 11, 2014, the Board of Directors of the Company terminated the Plan effective December 31, 2013. Prior to Plan termination, interests in oil and gas properties acquired, developed or sold during the year were allocated to the Plan on an annual basis as determined by the Compensation Committee of the Company’s Board of Directors. Once allocated, the interests (not legally conveyed) were fixed. Interest allocations prior to 1995 consisted of 2% 3% overriding royalty interests. Interest allocations after 1995 were 1.75% 5% of oil and gas sales less lease operating expenses and production taxes.

Employees vested in the Plan ratably at 20% per year over a five-year period. However, pursuant to the terms of the Plan, upon Plan termination effective December 31, 2013 all employees fully vested, and the Company is required to distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination. This distribution will include the value of proved undeveloped oil and gas properties (“PUDs”) awarded upon Plan termination and is based on forecasted commodity prices for crude oil and natural gas as of December 31, 2013. The fully vested lump sum cash payment to Plan participants will total $113.4 million and has been reflected as a current payable in accrued liabilities and other, as it will be distributed to Plan participants during the first half of 2015.

Table of Contents

Accrued compensation expense under the Plan for the six months ended June 30, 2014 primarily relates to the change in liability for employee vestings and PUDs assigned upon Plan termination and amounted to $23.6 million charged to general and administrative expense and $2.3 million charged to exploration expense. Accrued compensation expense under the Plan for the six months ended June 30, 2013 amounted to $21.5 million charged to general and administrative expense and $2.2 million charged to exploration expense.

Prior to Plan termination, the Company recorded non-cash changes in the present value of estimated future payments under the Plan as a separate line item in the consolidated statements of income. As a result of Plan termination, all changes in the Plan liability during 2014 related to cash termination payments to be made during 2015.

The following table presents changes in the Plan's estimated long-term liability (in thousands):

Long-term Production Participation Plan liability at January 1, 2014	$ 87,503
Change in liability for vesting and PUDs assigned upon Plan termination	25,888
Amount reflected as a current liability	(113,391)
Long-term Production Participation Plan liability at June 30, 2014	$ -

9. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

6.25% Convertible Perpetual Preferred Stock—In June 2009, the Company completed a public offering of 6.25% convertible perpetual preferred stock ("preferred stock"), selling 3,450,000 shares at a price of $100.00 per share. As a result of voluntary conversions and the Company exercising its right to mandatorily convert shares of preferred stock effective June 27, 2013, all 172,129 shares of preferred stock outstanding on March 31, 2013 were converted into 792,919 shares of common stock. As of June 30, 2014, no shares of preferred stock remained issued or outstanding.

Each holder of the preferred stock was entitled to an annual dividend of $6.25 per share to be paid quarterly in cash, common stock or a combination thereof on March 15, June 15, September 15 and December 15, once such dividend had been declared by Whiting's board of directors.

Equity Incentive Plan—At the Company's 2013 Annual Meeting held on May 7, 2013, shareholders approved the Whiting Petroleum Corporation 2013 Equity Incentive Plan (the "2013 Equity Plan"), which replaced the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "2003 Equity Plan") and includes the authority to issue 5,300,000 shares of the Company's common stock. Upon shareholder approval of the 2013 Equity Plan, the 2003 Equity Plan was terminated. The 2003 Equity Plan continues to govern awards that were outstanding as of the date of its termination, which remain in effect pursuant to their terms. Any shares netted or forfeited after May 7, 2013 under the 2003 Equity Plan will be available for future issuance under the 2013 Equity Plan. Under the 2013 Equity Plan, no employee or officer participant may be granted options for more than 600,000 shares of common stock, stock appreciation rights relating to more than 600,000 shares of common stock, or more than 300,000 shares of restricted stock during any calendar year. As of June 30, 2014, 5,044,045 shares of common stock remained available for grant under the 2013 Equity Plan.

Noncontrolling Interest—The Company's noncontrolling interest represents an unrelated third party's 25% ownership interest in Sustainable Water Resources, LLC. The table below summarizes the activity for the equity attributable to the noncontrolling interest (in thousands):

	Six Months Ended June 30,	
	2014	2013
Balance at January 1	$ 8,132	$ 8,184
Net income (loss)	(36)	(31)
Balance at June 30	$ 8,096	$ 8,153

10. INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three and six months ended June 30, 2014 and 2013 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to pre-tax income primarily because of state income taxes and estimated permanent differences.

The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in

Table of Contents

various jurisdictions, permanent and temporary differences, and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, additional information becomes known or as the tax environment changes.

11. EARNINGS PER SHARE

The reconciliations between basic and diluted earnings per share are as follows (in thousands, except per share data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Basic Earnings Per Share				
Numerator:				
Net income available to shareholders	$ 151,444	$ 134,956	$ 260,513	$ 221,219
Preferred stock dividends (1)	-	(225)	-	(494)
Net income available to common shareholders, basic	$ 151,444	$ 134,731	$ 260,513	$ 220,725
Denominator:				
Weighted average shares outstanding, basic	118,968	117,930	118,946	117,859
Diluted Earnings Per Share				
Numerator:				
Net income available to common shareholders, basic	$ 151,444	$ 134,731	$ 260,513	$ 220,725
Preferred stock dividends	-	269	-	538
Adjusted net income available to common shareholders, diluted	$ 151,444	$ 135,000	$ 260,513	$ 221,263
Denominator:				
Weighted average shares outstanding, basic	118,968	117,930	118,946	117,859
Restricted stock and stock options	1,059	267	1,099	321
Convertible perpetual preferred stock	-	704	-	749
Weighted average shares outstanding, diluted	120,027	118,901	120,045	118,929
Earnings per common share, basic	$ 1.27	$ 1.14	$ 2.19	$ 1.87
Earnings per common share, diluted	$ 1.26	$ 1.14	$ 2.17	$ 1.86

(1) For the three and six months ended June 30, 2013, amount includes a decrease of $0.04 million in preferred stock dividends for preferred stock dividends accumulated.

For the three months ended June 30, 2013, the diluted earnings per share calculation excludes (i) the dilutive effect of 814,932 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2013, and (ii) the dilutive effect of 945 common shares for stock options that were out-of-the-money.

For the six months ended June 30, 2013, the diluted earnings per share calculation excludes (i) the dilutive effect of 645,017 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2013, and (ii) the dilutive effect of 174 common shares for stock options that were out-of-the-money.

12. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers ("ASU 2014 09"). The objective of ASU 2014-09 is to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards. ASU 2014 09 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently evaluating the impact of adopting ASU 2014 09, but the standard is not expected to have a significant effect on its consolidated financial statements.

In February 2013, the FASB issued Accounting Standards Update No. 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date ("ASU 2013-04"). The objective of ASU 2013-04 is to provide guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU

2013 04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company adopted ASU 2013-04 effective January 1, 2014, which did not have an impact on the Company's consolidated financial statements.

In July 2013, the FASB issued Accounting Standards Update No. 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists ("ASU 2013-11"). The objective of ASU 2013-11 is to provide guidance on financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company adopted ASU 2013-11 effective January 1, 2014, which did not have an impact on the Company's consolidated financial statements, other than insignificant balance sheet reclassifications.

13. SUBSEQUENT EVENT

On July 13, 2014, Whiting and Kodiak Oil & Gas Corp. ("Kodiak") entered into a definitive agreement under which Whiting would acquire all of the outstanding common stock of Kodiak (the "Kodiak Acquisition"). Under the terms of the agreement, Kodiak shareholders will receive 0.177 of a share of Whiting common stock in exchange for each share of Kodiak common stock they own, representing consideration to each Kodiak shareholder of $13.90 per share based on the closing price of Whiting's common stock on July 11, 2014. Based on Whiting's stock price on such date, the transaction had a preliminary value of approximately $6.0 billion, including the assumption of Kodiak's net debt of $2.2 billion.

In conjunction with the Kodiak Acquisition, the Company secured underwritten financing to increase the borrowing base under Whiting Oil and Gas' credit facility to $4.5 billion, with aggregate commitments of $3.5 billion, of which $2.5 billion relates to commitments to extend revolving credit and $1.0 billion relates to a senior secured delayed draw term loan facility ("Delayed Draw Facility"). The Delayed Draw Facility may be used to provide cash consideration for any repurchase or redemption of Kodiak's outstanding senior notes in connection with the Kodiak Acquisition, to pay transaction costs and for other corporate purposes. The increase in the credit facility borrowing base and aggregate commitments only go into effect upon closing of the Kodiak Acquisition.

Completion of the Kodiak Acquisition is subject to the approval of both Whiting and Kodiak shareholders and certain court and regulatory approvals and customary closing conditions. The closing of this transaction is expected to occur in the fourth quarter of 2014.

Whiting and Kodiak each have the right to terminate the Kodiak Acquisition agreement in certain circumstances, including, but not limited to, (i) if the Kodiak Acquisition is not completed by January 9, 2015 (except that such date may be extended to March 10, 2015 if the only unsatisfied condition to the completion of the Kodiak Acquisition is the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended), (ii) the other party materially breaches its representations or covenants and such breach is not, or is not capable of being, cured within 30 days of notice, (iii) the Supreme Court of British Columbia fails to approve the Kodiak Acquisition, (iv) Whiting's or Kodiak's shareholders fail to approve the Kodiak Acquisition, or (v) if the other party's board of directors makes an adverse recommendation change. In the event that the Kodiak Acquisition agreement is terminated, Whiting could be subject to a termination fee of $130.0 million plus reimbursement of up to $10.0 million in Kodiak's expenses, under certain circumstances.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Unless the context otherwise requires, the terms "Whiting," "we," "us," "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in exploration, development, acquisition and production activities primarily in the Rocky Mountains and Permian Basin regions of the United States. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable successes and production growth. We believe the combination of acquisitions, subsequent development and organic drilling provides us with a broad set of growth alternatives and allows us to direct our capital resources to what we believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a balanced exploration and development program, while continuing to selectively pursue acquisitions that complement our existing core properties, such as the anticipated Kodiak Acquisition discussed below under "Acquisition and Divestiture Highlights". We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- allocating a portion of our exploration and development budget to leasing and exploring prospect areas;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows; and
- seeking property acquisitions that complement our core areas, such as the anticipated Kodiak Acquisition discussed below under "Acquisition and Divestiture Highlights".

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that established a presence in a new area of interest or that have complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis.

We continually evaluate our current property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2012:

	2012				2013				2014	
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Crude oil	$ 102.94	$ 93.51	$ 92.19	$ 88.20	$ 94.34	$ 94.23	$ 105.82	$ 97.50	$ 98.62	$ 102.98
Natural gas	$ 2.72	$ 2.21	$ 2.81	$ 3.41	$ 3.34	$ 4.10	$ 3.58	$ 3.60	$ 4.93	$ 4.68

Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserves. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and which is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil and natural gas prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

2014 Highlights and Future Considerations

Operational Highlights.

Sanish and Parshall Fields. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish and Parshall fields averaged 41.9 MBOE/d for the second quarter of 2014, which represents a 3% increase from 40.6 MBOE/d in the first quarter of 2014. As of June 30, 2014, we had three drilling rigs active in the Sanish field. Based on the success of our high density pilot programs in the Sanish field, we plan to commence a development program drilling nine wells per spacing unit in the area, an increase over our original plan of three to four wells per spacing unit.

Lewis & Clark/Pronghorn Fields. Our Lewis & Clark/Pronghorn fields are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). Net production in the Lewis & Clark/Pronghorn fields averaged 16.5 MBOE/d in the second quarter of 2014, which represents a 20% increase from 13.7 MBOE/d in the first quarter of 2014. As of June 30, 2014, we had two drilling rigs operating in the Pronghorn field, all of which are utilizing drilling pads, with two or three wells from each pad. Additionally, we have tested our new completion design in the Pronghorn field utilizing cemented liners and plug-and-perf technology and are encouraged by the results. As a result of these successes, we plan to use this completion procedure on all wells drilled in the area.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which primarily processes production from the Pronghorn area. In November 2012, we began connecting other operators' wells to the plant, and we added inlet compression during 2013 in order to fully utilize the plant's processing capability. Currently, there is inlet compression in place to process 35 MMcf/d, and as of June 30, 2014 the plant was processing over 19 MMcf/d. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and continue to operate the Belfield plant and facilities.

Hidden Bench/Tarpon Fields. Our Hidden Bench and Tarpon fields in McKenzie County, North Dakota target the Bakken and Three Forks formations. In the second quarter of 2014, net production from the Hidden Bench/Tarpon fields averaged 15.4 MBOE/d, which represents a 16% increase from 13.3 MBOE/d in the first quarter of 2014. We have also implemented our new completion design at our Hidden Bench field, utilizing cemented liners and plug-and-perf technology, and the new design has generated positive results which include improved initial production rates. Based on the success of our high density drilling pilot at the Hidden Bench field, we plan to commence a development program drilling eight wells per spacing unit in the area, an increase over our original plan of four wells per spacing unit. In the Tarpon field, we have drilled ten productive wells as of June 30, 2014 and are currently drilling additional wells in this area.

Missouri Breaks Field. Our Missouri Breaks field, which is located in Richland County, Montana and McKenzie County, North Dakota, targets the Middle Bakken formation. In the second quarter of 2014, net production from the Missouri Breaks field averaged 4.4 MBOE/d, representing a 23% increase from 3.6 MBOE/d in the first quarter of 2014. We have implemented our new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, and the new design has improved initial production rates. In addition, we have completed one well using our new coiled tubing fracture stimulation method and one well using our new slickwater fracture stimulation method, and we are encouraged by the initial results from both of these techniques. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area.

Redtail Field. Our Redtail field in the Denver Julesberg Basin (“DJ Basin”) in Weld County, Colorado targets the Niobrara formation. In the second quarter of 2014, net production from the Redtail field averaged 7.2 MBOE/d, representing a 59% increase from 4.6 MBOE/d in the first quarter of 2014. Our development plan at Redtail currently includes drilling up to eight Niobrara “B” wells per spacing unit and eight Niobrara “A” wells per spacing unit. In 2014, we plan to test a high-density pattern in the Niobrara “A”, “B” and “C” zones drilling 32 wells per spacing unit. As of June 30, 2014, we had three drilling rigs operating in this area and we added a fourth rig in mid-July. We plan to add a fifth rig in this area in the second half of 2014. We have implemented our new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, which has been yielding improved production results.

The associated gas that is produced along with the Niobrara crude oil from our Redtail field must be processed before being sold. In April 2014, we completed the construction of and brought online a gas processing plant for this area. The plant’s inlet capacity is 20 MMcf/d, and we plan to further expand the plant’s capacity to 70 MMcf/d in the first quarter of 2015.

North Ward Estes Field. The North Ward Estes field is located in the Ward and Winkler counties in Texas, and we continue to have significant development and related infrastructure activity in this field since we acquired it in 2005. Our activity at North Ward Estes to date has resulted in production increases and substantial reserve additions, and our expansion of the CO_2 flood in this area continues to generate positive results.

North Ward Estes has been responding positively to the water and CO_2 floods that we initiated in May 2007. We are currently injecting CO_2 in one of the largest phases of our eight-phase project at North Ward Estes, and several of the phases of the CO_2 flood are continuing to respond. Net production from North Ward Estes averaged 10.0 MBOE/d for the second quarter of 2014, representing a slight increase from 9.8 MBOE/d in the first quarter of 2014. As of June 30, 2014, we were injecting approximately 370 MMcf/d of CO_2 into the field, over half of which is recycled.

Acquisition and Divestiture Highlights.

Kodiak Acquisition. On July 13, 2014, we entered into a definitive agreement with Kodiak Oil & Gas Corp. ("Kodiak") under which we would acquire all of the outstanding common stock of Kodiak (the "Kodiak Acquisition"). Under the terms of the agreement, Kodiak shareholders will receive 0.177 of a share of Whiting common stock in exchange for each share of Kodiak common stock they own, representing consideration to each Kodiak shareholder of $13.90 per share based on the closing price of Whiting's common stock on July 11, 2014. Based on Whiting's stock price on such date, the transaction had a preliminary value of approximately $6.0 billion, including the assumption of Kodiak's net debt of $2.2 billion. Following the Kodiak Acquisition, shareholders of Whiting are expected to own approximately 71% of the combined company on a fully diluted basis, and shareholders of Kodiak are expected to own approximately 29%. This transaction is expected to be a tax-free exchange to Kodiak's U.S. shareholders.

In conjunction with the Kodiak Acquisition, we secured underwritten financing to increase the borrowing base under Whiting Oil and Gas' credit facility to $4.5 billion, with aggregate commitments of $3.5 billion, of which $2.5 billion relates to commitments to extend revolving credit and $1.0 billion relates to a senior secured delayed draw term loan facility ("Delayed Draw Facility"). The Delayed Draw Facility may be used to provide cash consideration for any repurchase or redemption of Kodiak's outstanding senior notes in connection with the Kodiak Acquisition, to pay transaction costs and for other corporate purposes. The increase in the credit facility borrowing base and aggregate commitments only go into effect upon closing of the Kodiak Acquisition and are expected to be sufficient to fund the combined company's ongoing liquidity needs.

Completion of the Kodiak Acquisition is subject to the approval of both Whiting and Kodiak shareholders and certain court and regulatory approvals and customary closing conditions. The closing of this transaction is expected to occur in the fourth quarter of 2014.

We and Kodiak each have the right to terminate the Kodiak Acquisition agreement in certain circumstances, including, but not limited to, (i) if the Kodiak Acquisition is not completed by January 9, 2015 (except that such date may be extended to March 10, 2015 if the only unsatisfied condition to the completion of the Kodiak Acquisition is the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended), (ii) the other party materially breaches its representations or covenants and such breach is not, or is not capable of being, cured within 30 days of notice, (iii) the Supreme Court of British Columbia fails to approve the Kodiak Acquisition, (iv) Whiting's or Kodiak's shareholders fail to approve the Kodiak Acquisition, or (v) if the other party's board of directors makes an adverse recommendation change. In the event that the Kodiak Acquisition agreement is terminated, we could be subject to a termination fee of $130.0 million plus reimbursement of up to $10.0 million in Kodiak's expenses, under certain circumstances.

Big Tex Divestiture. In March 2014, we completed the sale of approximately 49,900 gross (41,000 net) acres, which consisted mainly of undeveloped acreage as well as our interests in certain producing oil and gas wells, in our Big Tex prospect located in the Delaware Basin of Texas for a cash purchase price of $75.6 million (subject to post-closing adjustments) resulting in a pre-tax gain on sale of $12.4 million. With this divestiture, we no longer own any interests in the Big Tex prospect.

Table of Contents

Results of Operations

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

	Six Months Ended June 30,	
	2014	2013
Net production:		
Oil (MMBbl)	15.3	13.0
NGLs (MMBbl)	1.4	1.4
Natural gas (Bcf)	13.9	13.0
Total production (MMBOE)	19.0	16.5
Net sales (in millions):		
Oil (1)	$ 1,388.5	$ 1,148.1
NGLs	65.2	56.5
Natural gas	93.3	52.4
Total oil, NGL and natural gas sales	$ 1,547.0	$ 1,257.0
Average sales prices:		
Oil (per Bbl) (1)	$ 91.04	$ 88.65
Effect of oil hedges on average price (per Bbl)	(0.38)	(0.95)
Oil net of hedging (per Bbl)	$ 90.66	$ 87.70
Average NYMEX price (per Bbl)	$ 100.81	$ 94.28
NGLs (per Bbl)	$ 45.47	$ 40.20
Natural gas (per Mcf)	$ 6.73	$ 4.04
Average NYMEX price (per Mcf)	$ 4.80	$ 3.72
Cost and expenses (per BOE):		
Lease operating expenses	$ 12.27	$ 12.41
Production taxes	$ 6.79	$ 6.36
Depreciation, depletion and amortization expense	$ 26.52	$ 25.70
General and administrative expenses	$ 3.57	$ 3.52

(1) Before consideration of hedging transactions.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $290.0 million to $1,547.0 million when comparing the first half of 2014 to the same period in 2013. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 18%, and our natural gas sales volumes increased 7% between periods, while our NGL sales volumes remained consistent between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon, Sanish and Parshall, Redtail, Missouri Breaks and Lewis & Clark fields. During the first half of 2014, oil production from our Hidden Bench/Tarpon fields increased 1,440 MBbl, oil production from our Sanish and Parshall fields increased 825 MBbl, oil production from our Redtail field increased 645 MBbl, oil production from our Missouri Breaks field increased 270 MBbl and oil production from our Lewis & Clark field increased 180 MBbl over the same period in 2013. These production increases were partially offset by the sale of our Postle field, which had oil production of

1,175 MBbl in the first half of 2013 but which was fully divested in July 2013. The gas volume increase between periods was primarily the result of new wells drilled and completed during the past twelve months, which caused increases in associated gas production of 920 MMcf at our Hidden Bench/Tarpon fields and 715 MMcf at our Sanish and Parshall fields. These gas volume increases were largely offset by normal field production decline across several of our areas, the most notable of which was our Flat Rock field where production volumes decreased 345 MMcf when comparing the first half of 2014 to the same period in 2013.

In addition to the above crude oil and natural gas production-related increases in net revenue were increases in the average sales prices realized for oil, NGLs and natural gas in the first half of 2014 compared to 2013. Our average price for oil before the effects of hedging increased 3%, our average price for NGLs increased 13%, and our average price for natural gas increased 67% between periods.

Table of Contents

Gain on Sale of Properties. During the first half of 2014, we sold undeveloped acreage as well as our interests in certain producing oil and gas wells in the Big Tex prospect for net proceeds of $75.6 million in cash, which resulted in a pre-tax gain on sale of $12.4 million. There were no other property divestitures resulting in a significant gain or loss on sale during the first half of 2014 or 2013.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first half of 2014 were $233.1 million, a $28.2 million increase over the same period in 2013. Higher LOE in 2014 were primarily related to a $34.6 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months, partially offset by a decrease in well workover activity. Workovers decreased from $40.8 million in the first half of 2013 to $34.4 million in the first half of 2014, primarily due to a lower number of well workovers being conducted at our CO2 projects at North Ward Estes and at our Postle field, which we sold in July 2013.

Our lease operating expenses on a BOE basis, however, decreased during the first half of 2014. LOE per BOE amounted to $12.27 during the first half of 2014, which was down from $12.41 per BOE during the first half of 2013. This decrease was mainly due to higher overall production volumes between periods and the decline in well workover costs, as discussed above.

Production Taxes. Our production taxes during the first half of 2014 were $128.9 million, a $23.8 million increase over the same period in 2013, which increase was primarily due to higher oil, NGL and natural gas sales between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.3% and 8.4% for the first half of 2014 and 2013, respectively.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $79.2 million in 2014 as compared to the first half of 2013. The components of our DD&A expense were as follows (in thousands):

	Six Months Ended June 30,	
	2014	2013
Depletion	$ 494,738	$ 416,903
Depreciation	2,493	2,083
Accretion of asset retirement obligations	6,543	5,619
Total	$ 503,774	$ 424,605

DD&A increased in the first half of 2014 primarily due to $77.8 million in higher depletion expense between periods. Of this increase, $64.4 million related to an increase in our overall production volumes during the first quarter of 2014 and $13.4 million related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $26.52 for the first half of 2014 was 3% higher than the rate of $25.70 for the same period in 2013 due to $2,566.0 million in drilling and development expenditures during the past twelve months, which were largely offset by reserve additions over this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $7.1 million in the first half of 2014 as compared to the same period in 2013. The components of our exploration and impairment costs were as follows (in thousands):

	Six Months Ended June 30,	
	2014	2013
Exploration	$ 37,588	$ 43,209
Impairment	36,031	37,464
Total	$ 73,619	$ 80,673

Exploration costs decreased $5.6 million during the first half of 2014 as compared to the same period in 2013 primarily due to lower exploratory dry hole expenses. Exploratory dry hole costs for the first half of 2014 totaled $3.6 million, primarily related to one exploratory dry hole drilled in the Rocky Mountains region. During the first half of 2013, exploratory dry hole costs totaled $11.6 million, primarily related to two exploratory dry holes drilled in the Permian Basin and Rocky Mountains regions during the second quarter of 2013.

Impairment expense in the first half of 2014 and 2013 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $35.8 million in the first half of 2014 as compared to $36.4 million in the first half of 2013.

General and Administrative Expenses. We report general and administrative expenses net of third-party reimbursements and internal allocations. The components of our general and administrative expenses were as follows (in thousands):

Table of Contents

	Six Months Ended June 30,	
	2014	2013
General and administrative expenses	$ 126,451	$ 112,501
Reimbursements and allocations	(58,562)	(54,403)
General and administrative expenses, net	$ 67,889	$ 58,098

General and administrative expense before reimbursements and allocations increased $14.0 million during the first half of 2014 as compared to the same period in 2013 primarily due to higher employee compensation. Employee compensation increased $8.5 million in the first half of 2014 as compared to the same period in 2013 due to personnel hired during the past twelve months and general pay increases. However, our general and administrative expenses as a percentage of oil, NGL and natural gas sales decreased slightly from 5% in the first half of 2013 to 4% for the first half of 2014.

General and administrative expense for the six months ended June 30, 2014 and 2013 includes $23.6 million and $21.5 million, respectively, for accrued compensation under our Production Participation Plan (the "Plan"). On June 11, 2014, the Plan was terminated effective December 31, 2013. Accordingly, there will be no accrued compensation expense under the Plan going forward. Refer to the Deferred Compensation footnote in the notes to consolidated financial statements for more information. Beginning January 1, 2015, we will implement a new cash bonus structure for our employees to replace the terminated Plan.

The increase in reimbursements and allocations for the first half of 2014 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Six Months Ended June 30,	
	2014	2013
Senior Notes and Senior Subordinated Notes	$ 73,031	$ 20,125
Credit agreement	2,312	20,080
Amortization of debt issue costs and premium	7,342	4,950
Other	26	38
Capitalized interest	(1,522)	(602)
Total	$ 81,189	$ 44,591

The increase in interest expense of $36.6 million between periods was mainly attributable to $52.9 million in higher interest costs incurred on our notes during 2014 and a $2.4 million increase in amortization of debt issue costs during the first half of 2014 as compared to the first half of 2013. These increases are due to our September 2013 issuance of $1,100.0 million of 5% Senior Notes due 2019 and $1,200.0 million of 5.75% Senior Notes due 2021. These increases were partially offset by a $17.8 million decrease in the amount of interest incurred on our credit agreement during the first half of 2014 as compared to the first half of 2013 due to lower borrowings outstanding under this facility in 2014. Our weighted average debt outstanding during the first half of 2014 was $2,653.3 million versus

$2,177.5 million for the first half of 2013. Our weighted average effective cash interest rate was 5.7% during the first half of 2014 compared to 3.7% for the first half of 2013.

Change in Production Participation Plan Liability. In 2013, this non-cash expense represented the change in the vested present value of estimated future payments to be made to participants under our Production Participation Plan. On June 11, 2014, we terminated the Plan effective December 31, 2013. Accordingly, there was no such expense for the six months ended June 30, 2014, nor will there be in any future periods, as all changes in the Plan liability during 2014 related to incremental cash payments to be made to Plan participants in 2015 as a result of its termination. These incremental cash payments to Plan participants have been primarily reflected as charges to general and administrative expense as discussed above. Refer to the Deferred Compensation footnote in the notes to consolidated financial statements for more information.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment from the counterparty. Commodity derivative (gain) loss, net amounted to a loss of $50.6 million for the six months ended June 30, 2014 mainly due to the upward shift in the futures curve of forecasted commodity prices (“forward price curve”) for crude oil from January 1, 2014 (or the 2014 date on which new contracts were entered into) to June 30, 2014. Commodity derivative (gain) loss, net for the six months ended June 30, 2013 resulted in a loss of $1.1 million due to the less significant upward shift in the same forward price curve from January 1, 2013 (or the 2013 date on which prior year contracts were entered into) to June 30, 2013.

Table of Contents

See Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of July 1, 2014.

Income Tax Expense. Income tax expense totaled $176.3 million for the first half of 2014 as compared to $124.5 million of income tax for the first half of 2013, an increase of $51.7 million that was mainly related to $91.0 million in higher pre-tax income between periods.

Our effective tax rates for the periods ending June 30, 2014 and 2013 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate increased from 36.0% for the first half of 2013 to 40.4% for the first half of 2014. This increase is mainly a result of expanded activity in states with higher corporate tax rates, additional tax expense for restricted stock awards that did not vest and additional state tax deductions recognized in the first half of 2013.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

	Three Months Ended June 30,	
	2014	2013
Net production:		
Oil (MMBbl)	8.0	6.7
NGLs (MMBbl)	0.8	0.7
Natural gas (Bcf)	7.2	6.6
Total production (MMBOE)	10.0	8.5
Net sales (in millions):		
Oil (1)	$ 745.2	$ 597.5
NGLs	30.9	26.2
Natural gas	49.7	28.2
Total oil, NGL and natural gas sales	$ 825.8	$ 651.9
Average sales prices:		
Oil (per Bbl) (1)	$ 93.03	$ 89.15
Effect of oil hedges on average price (per Bbl)	(0.64)	(1.05)
Oil net of hedging (per Bbl)	$ 92.39	$ 88.10
Average NYMEX price (per Bbl)	$ 102.98	$ 94.23
NGLs (per Bbl)	$ 39.30	$ 37.80
Natural gas (per Mcf)	$ 6.95	$ 4.27
Average NYMEX price (per Mcf)	$ 4.68	$ 4.10
Cost and expenses (per BOE):		
Lease operating expenses	$ 11.85	$ 12.37
Production taxes	$ 6.89	$ 6.33
Depreciation, depletion and amortization expense	$ 26.88	$ 26.29
General and administrative expenses	$ 3.56	$ 3.44

(1) Before consideration of hedging transactions.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $173.9 million to $825.8 million when comparing the second quarter of 2014 to the same period in 2013. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 20%, our natural gas sales volumes increased 8%, and our NGL sales volumes increased 13% between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon, Sanish and Parshall, Redtail and Lewis & Clark fields. During the second quarter of 2014, oil production from our Hidden Bench/Tarpon fields increased 730 MBbl, oil production from our Sanish and Parshall fields increased 430 MBbl, oil production from our Redtail field increased 350 MBbl, and oil production from our Lewis & Clark field increased 195 MBbl over the same period in 2013. These production increases were partially offset by the sale of our Postle field, which had oil production of 585 MBbl in the second quarter of 2013 but which was fully divested in July 2013. The gas volume increase between periods was primarily the result of new wells drilled and completed during the past twelve months, which caused increases in associated gas production of 485 MMcf at our Hidden Bench/Tarpon fields, 300 MMcf at our Sanish and Parshall fields and 235 MMcf at our Redtail field. These gas volume increases were partially offset by normal field production decline across several of our areas.

Table of Contents

In addition to the above crude oil, natural gas and NGL production-related increases in net revenue were increases in the average sales prices realized for oil, NGLs and natural gas in the second quarter of 2014 compared to 2013. Our average price for oil before the effects of hedging increased 4%, our average price for NGLs increased 4%, and our average price for natural gas increased 63% between periods.

Lease Operating Expenses. Our lease operating expenses during the second quarter of 2014 were $118.4 million, a $13.3 million increase over the same period in 2013. Higher LOE in 2014 were primarily related to a $21.8 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months, partially offset by a decrease in well workover activity. Workovers decreased from $21.1 million in the second quarter of 2013 to $12.6 million in the second quarter of 2014, primarily due to a lower number of well workovers being conducted at our CO2 projects at North Ward Estes and at our Postle field, which we sold in July 2013.

Our lease operating expenses on a BOE basis, however, decreased during the second quarter of 2014. LOE per BOE amounted to $11.85 during the second quarter of 2014, which was down from $12.37 per BOE during the second quarter of 2013. This decrease was mainly due to higher overall production volumes between periods and the decline in well workover costs, as discussed above.

Production Taxes. Our production taxes during the second quarter of 2014 were $68.9 million, a $15.0 million increase over the same period in 2013, which increase was primarily due to higher oil, NGL and natural gas sales between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis remained consistent at 8.3% for the second quarter of 2014 and 2013.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization expense increased $45.1 million in 2014 as compared to the second quarter of 2014. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended June 30,	
	2014	2013
Depletion	$ 263,786	$ 220,081
Depreciation	1,276	999
Accretion of asset retirement obligations	3,447	2,366
Total	$ 268,509	$ 223,446

DD&A increased in the second quarter of 2014 primarily due to $43.7 million in higher depletion expense between periods. Of this increase, $39.4 million related to an increase in our overall production volumes during the second quarter of 2014 and $4.3 million related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $26.88 for the second quarter of 2014 was 2% higher than the rate of $26.29 for the same period in 2013 due to $2,566.0 million in drilling and development expenditures during the past twelve months, which were largely offset by reserve additions over this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $11.9 million in the second quarter of 2014 as compared to the same period in 2013. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended June 30,	
	2014	2013
Exploration	$ 13,466	$ 24,343
Impairment	18,046	19,050
Total	$ 31,512	$ 43,393

Exploration costs decreased $10.9 million during the second quarter of 2014 as compared to the same period in 2013 primarily due to lower exploratory dry hole expenses. We did not drill any exploratory dry holes in the second quarter of 2014, while we drilled two exploratory dry holes in the Permian Basin and Rocky Mountains regions totaling $11.6 million during the second quarter of 2013.

Impairment expense in the second quarter of 2014 and 2013 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $17.9 million in the second quarter of 2014 as compared to $18.1 million in the second quarter of 2013.

General and Administrative Expenses. We report general and administrative expenses net of third-party reimbursements and internal allocations. The components of our general and administrative expenses were as follows (in thousands):

Table of Contents

	Three Months Ended June 30,	
	2014	2013
General and administrative expenses	$ 64,780	$ 57,429
Reimbursements and allocations	(29,225)	(28,216)
General and administrative expenses, net	$ 35,555	$ 29,213

General and administrative expense before reimbursements and allocations increased $7.4 million during the second quarter of 2014 as compared to the same period in 2013 primarily due to higher employee compensation. Employee compensation increased $4.2 million in the second quarter of 2014 as compared to the same period in 2013 due to personnel hired during the past twelve months and general pay increases. However, our general and administrative expenses as a percentage of oil, NGL and natural gas sales remained consistent at 4% for the second quarter of 2014 and 2013.

General and administrative expense for the three months ended June 30, 2014 and 2013 includes $12.6 million and $11.2 million, respectively, for accrued compensation under our Production Participation Plan. On June 11, 2014, the Plan was terminated effective December 31, 2013. Accordingly, there will be no accrued compensation expense under the Plan going forward. Refer to the Deferred Compensation footnote in the notes to consolidated financial statements for more information. Beginning January 1, 2015, we will implement a new cash bonus structure for our employees to replace the terminated Plan.

The increase in reimbursements and allocations for the second quarter of 2014 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Three Months Ended June 30,	
	2014	2013
Senior Notes and Senior Subordinated Notes	$ 36,688	$ 10,063
Credit agreement	1,190	10,808
Amortization of debt issue costs and premium	1,983	2,516
Other	1	14
Capitalized interest	(817)	(280)
Total	$ 39,045	$ 23,121

The increase in interest expense of $15.9 million between periods was mainly attributable to $26.6 million in higher interest costs incurred on our notes during 2014. This increase is due to our September 2013 issuance of $1,100.0 million of 5% Senior Notes due 2019 and $1,200.0 million of 5.75% Senior Notes due 2021. This increase was partially offset by a $9.6 million decrease in the amount of interest incurred on our credit agreement during the second quarter of 2014 as compared to the second quarter of 2013 due to lower borrowings outstanding under this facility in

2014. Our weighted average debt outstanding during the second quarter of 2014 was $2,656.6 million versus $2,325.3 million for the second quarter of 2013. Our weighted average effective cash interest rate was 5.7% during the second quarter of 2014 compared to 3.6% for the second quarter of 2013.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment from the counterparty. Commodity derivative (gain) loss, net amounted to a loss of $26.1 million for the three months ended June 30, 2014 mainly due to the upward shift in the forward price curve for crude oil from April 1, 2014 (or the 2014 date on which new contracts were entered into) to June 30, 2014. Commodity derivative (gain) loss, net for the three months ended June 30, 2013 resulted in a gain of $30.2 million due to the downward shift in the same forward price curve from April 1, 2013 (or the 2013 date on which new contracts were entered into) to June 30, 2013.

See Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of July 1, 2014.

Income Tax Expense. Income tax expense totaled $99.9 million for the second quarter of 2014 as compared to $73.0 million of income tax for the second quarter of 2013, an increase of $26.9 million that was mainly related to $43.4 million in higher pre-tax income between periods.

Our effective tax rates for the periods ending June 30, 2014 and 2013 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate increased from 35.1% for the

Table of Contents

second quarter of 2013 to 39.8% for the second quarter of 2014. This increase is mainly a result of expanded activity in states with higher corporate tax rates and additional state tax deductions recognized in the second quarter of 2013.

Liquidity and Capital Resources

Overview. At June 30, 2014, we had $227.1 million of cash on hand and $4,089.0 million of equity, while at December 31, 2013, we had $699.5 million of cash on hand and $3,828.6 million of equity.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity hedge contracts. Oil accounted for 80% and 78% of our total production in the first half of 2014 and 2013, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in NGL or natural gas prices. As of July 1, 2014, we had derivative contracts covering the sale of approximately 50% of our forecasted oil production volumes for the remainder of 2014.

During the first half of 2014, we generated $891.7 million of cash provided by operating activities, an increase of $151.4 million over the same period in 2013. Cash provided by operating activities increased primarily due to higher realized sales prices for oil, NGLs and natural gas and higher crude oil, NGL and natural gas production volumes during the first half of 2014. These positive factors were partially offset by increased lease operating expenses, production taxes, general and administrative and cash interest expense in the first half of 2014 as compared to the same period in 2013. Refer to "Results of Operations" for more information on the impact of prices and volumes on revenues and for more information on increases and decreases in certain expenses during the first half of 2014.

During the first half of 2014, cash flows from operating activities and cash on hand plus $83.2 million of proceeds from the sale of properties were used to finance $1,326.1 million of drilling and development expenditures, $44.5 million of oil and gas property acquisitions, $34.7 million for purchases of other property and equipment and $26.4 million for the final payment under our Tax Sharing and Indemnification Agreement with Alliant Energy Corporation.

Exploration, Development and Undeveloped Acreage Expenditures. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region (in thousands):

	Six Months Ended June 30,	
	2014	2013
Rocky Mountains	$ 1,241,029	$ 944,189
Permian Basin (1)	187,177	163,524
Other (2)	23,712	124,749
Total incurred	$ 1,451,918	$ 1,232,462

(1) For the six months ended June 30, 2014, amount includes $21.5 million primarily related to the development of CO_2 reserves and related facilities at our Bravo Dome field in New Mexico. For the six months ended June 30, 2013, amount includes $10.6 million primarily related to the acquisition of undeveloped acreage at our Bravo Dome field in New Mexico.

(2) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2014 exploration and development budget is $2.8 billion, which we expect to fund substantially with net cash provided by our operating activities, cash on hand and borrowings under our credit facility. This represents a slight increase from the $2,675.2 million incurred on exploration, development and acreage expenditures during 2013, and based on this level of capital spending, we are forecasting production growth in 2014 over our 2013 production level of 34.3 MMBOE. We expect to allocate $2,533.0 million of our 2014 budget to exploration and development activity, $116.0 million for undeveloped acreage and $151.0 million for facilities. Although we have only budgeted $116.0 million for undeveloped leasehold purchases in 2014, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should additional attractive acquisition opportunities arise or exploration and development expenditures exceed $2.8 billion, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, agreements with industry partners or divestitures of certain oil and gas property interests. Our level of exploration, development and acreage expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months, including obligations arising as a result of the anticipated Kodiak Acquisition, and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments, comply with our debt covenants, and meet other obligations that may arise from our oil and gas operations.

Table of Contents

Credit Agreement. Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of June 30, 2014 had a borrowing base of $2.8 billion, of which $1.2 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.8 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of June 30, 2014, we had $1,197.0 million of available borrowing capacity, which was net of $3.0 million in letters of credit and no borrowings outstanding. In April 2014, Whiting Oil and Gas entered into an amendment to its credit agreement that extended the principal repayment date from April 2016 to the earlier of (i) April 2, 2019 or (ii) with certain exceptions, the date that is 91 days prior to the scheduled maturity of any permitted additional unsecured senior or senior subordinated notes, which includes the Company's 5% Senior Notes due March 2019, unless redeemed earlier in accordance with the credit agreement.

In conjunction with the Kodiak Acquisition, we secured underwritten financing to increase the borrowing base under Whiting Oil and Gas' credit facility to $4.5 billion, with aggregate commitments of $3.5 billion, of which $2.5 billion relates to commitments to extend revolving credit and $1.0 billion relates to a senior secured delayed draw term loan facility ("Delayed Draw Facility"). The Delayed Draw Facility may be used to provide cash consideration for any repurchase or redemption of Kodiak's outstanding senior notes in connection with the Kodiak Acquisition, to pay transaction costs and for other corporate purposes. The increase in the credit facility borrowing base and aggregate commitments only go into effect upon closing of the Kodiak Acquisition and are expected to be sufficient to fund the combined company's ongoing liquidity needs. The Kodiak Acquisition is expected to close in the fourth quarter of 2014.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of June 30, 2014, $47.0 million was available for additional letters of credit under the agreement.

The amended credit agreement provides for interest only payments until the expiration date of the agreement, when all outstanding borrowings are due. Interest accrues at our option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, we also incur commitment fees as set forth in the table below on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%

Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of the net assets of Whiting Oil and Gas. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. We were in compliance with our covenants under the credit agreement as of June 30, 2014.

For further information on the loan security related to our credit agreement, refer to the Long-Term Debt footnote in the notes to consolidated financial statements.

Senior Notes and Senior Subordinated Notes. In September 2013, we issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and also in September 2013, we issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021. In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018.

Table of Contents

The indentures governing the notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of June 30, 2014. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The table below does not include any penalties that may be incurred under our physical delivery contracts, since we cannot predict with accuracy whether we will be subject to any such penalties or the amount and timing of any such penalties if incurred. The following table summarizes our obligations and commitments as of June 30, 2014 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

	Payments due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 2,650,000	$ -	$ -	$ 1,450,000	$ 1,200,000
Cash interest expense on debt (2)	818,521	146,750	293,500	260,396	117,875
Derivative contract liability fair value (3)	24,044	24,044	-	-	-
Asset retirement obligations (4)	165,555	8,311	16,569	16,622	124,053
Purchase obligations (5)	669,912	127,148	236,891	102,576	203,297
Drilling rig contracts (6)	126,941	79,958	46,983	-	-
Operating leases (7)	26,973	6,578	11,344	8,252	799
Construction and drilling contract (8)	31,945	18,045	6,400	7,500	-
Production Participation Plan liability (9)	113,391	113,391	-	-	-
Total	$ 4,627,282	$ 524,225	$ 611,687	$ 1,845,346	$ 1,646,024

(1) Long-term debt consists of the principal amounts of the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021.
(2) Cash interest expense on the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021 is estimated assuming no principal repayment until the due dates of the instruments. No cash interest expense is assumed on the credit facility as there were no borrowings outstanding as of June 30, 2014.
(3) The above derivative obligation at June 30, 2014 consists of a $24.0 million fair value liability for derivative contracts we have entered into in the form of costless collars, to hedge our exposure to crude oil price fluctuations.

With respect to only a portion of our open derivative contracts at June 30, 2014 with certain counterparties, the forward price curve for crude oil generally exceeded the price curve that was in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market risk and commodity price volatility.

(4) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants and facilities.

(5) We have five take-or-pay purchase agreements, of which one agreement expires each year from 2014 to 2017 and one agreement expires in 2029. Three of these agreements contain commitments to buy certain volumes of CO_2 for use in our North Ward Estes EOR project in Texas. Under the remaining two take-or-pay agreements, we have committed to buy certain volumes of water for use in the fracture stimulation process of wells in our Redtail field. Under the terms of these agreements, we are obligated to purchase a minimum volume of CO_2 or water, as the case may be, or else pay for any deficiencies at the price stipulated in the contract. In addition, we have two ship-or-pay agreements with different suppliers, one expiring in 2016 and one expiring in 2017, whereby we have committed to transport a minimum daily volume of CO_2 or water, as the case may be, via certain pipelines or else pay for any deficiencies at a price stipulated in the contracts. The CO_2 volumes planned for use in

the EOR project in our North Ward Estes field and the water volumes planned for use at our Redtail field currently exceed the minimum volumes specified in all of these agreements. Therefore, we expect to avoid any payments for deficiencies. The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts. However, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

(6) We currently have 12 drilling rigs under long-term contract, of which four drilling rigs expire in 2014, three in 2015, four in 2016 and one in 2017. All of these rigs are operating in the Rocky Mountains region. As of June 30, 2014, early termination of the remaining contracts would require termination penalties of $98.3 million, which would be in lieu of paying the remaining drilling commitments of $126.9 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(7) We lease 172,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2018, 47,900 square feet of office space in Midland, Texas expiring in 2020 and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016. In addition, we entered into a lease for several residential apartments in Watford City and Dickinson, North Dakota under an operating lease agreement expiring in 2015.

(8) We entered into a contractual obligation to spend up to $51.4 million on the construction of certain facilities and field infrastructure and the drilling of forty-six CO_2 wells in our Bravo Dome field. If we fail to spend the required amounts by the dates set forth in the agreement, we will be required to pay the remaining unspent capital expenditures as liquidated damages. However, we expect to fulfill our obligations under this contract and thereby avoid any payments for deficiencies. We do not have any volumetric CO_2 delivery or supply commitments associated with this contract.

(9) In June 2014, we terminated our Production Participation Plan effective December 31, 2013. Pursuant to the terms of the Plan, upon termination we are required to distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination. This distribution will be made during the first half of 2015.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement and the Delayed Draw Facility, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations. exploration and development activities and obligations arising as a result of the anticipated Kodiak Acquisition.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to the Adopted and Recently Issued Accounting Pronouncements footnote in the notes to consolidated financial statements.

Critical Accounting Policies and Estimates

Information regarding critical accounting policies and estimates is contained in Item 7 of our Annual Report on Form 10 K for the fiscal year ended December 31, 2013.

Effects of Inflation and Pricing

We experienced increased costs during 2013 and the first half of 2014 due to increased demand for oil field products and services. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we "expect," "intend," "plan," "estimate," "anticipate," "believe" or "shou the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

These risks and uncertainties include, but are not limited to: the ability to obtain shareholder, court and regulatory approvals of the Kodiak Acquisition; the ability to complete the proposed Kodiak Acquisition on anticipated terms and timetable; our and Kodiak's ability to integrate successfully after the Kodiak Acquisition and achieve anticipated benefits from the Kodiak Acquisition; the possibility that various closing conditions for the Kodiak Acquisition may not be satisfied or waived; declines in oil, NGL or natural gas prices; our level of success in exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; our ability to obtain sufficient quantities of CO2 necessary to carry out our EOR projects; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; impacts to financial statements as a result of impairment write-downs; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations and acquisitions; federal and state initiatives relating to the regulation of hydraulic fracturing; the potential impact of federal debt reduction initiatives and tax reform legislation being considered by the U.S. Federal Government that could have a negative effect on the oil and gas industry; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions and the risks related thereto; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption "Risk Factors" in our Annual Report on Form 10 K for the period ended December 31, 2013. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Quarterly Report on Form 10-Q.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2013 and have not materially changed since that report was filed.

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. Based on production for the first half of 2014, our income before income taxes for the six months ended June 30, 2014 would have moved up or down $138.9 million for each 10% change in oil prices per Bbl, $6.5 million for each 10% change in NGL prices per Bbl and $9.3 million for each 10% change in natural gas prices per Mcf.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars, although we evaluate and have entered into other forms of derivative instruments as well. Currently, we do not apply hedge accounting, and therefore all changes in commodity derivative fair values are recorded immediately to earnings.

Commodity Derivative Contracts—The collared hedges shown in the tables below have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to reduce our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil collars outstanding as of June 30, 2014, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of June 30, 2014 would cause a decrease or increase, respectively, of $74.1 million in our commodity derivative (gain) loss.

Our outstanding hedges as of July 1, 2014 are summarized below:

Whiting Petroleum Corporation

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Sub-Floor/Floor/Ceiling
Three-way collars (1)	Crude oil	07/2014 to 09/2014	1,480,000	$71.82/$85.68/$103.85
	Crude oil	10/2014 to 12/2014	1,480,000	$71.82/$85.68/$103.85
	Crude oil	01/2015 to 03/2015	100,000	$70.00/$85.00/$107.90
	Crude oil	04/2015 to 06/2015	100,000	$70.00/$85.00/$107.90
	Crude oil	07/2015 to 09/2015	100,000	$70.00/$85.00/$107.90
	Crude oil	10/2015 to 12/2015	100,000	$70.00/$85.00/$107.90

(1)

A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

Fixed-differential Crude Oil Contracts. We have entered into two fixed-differential crude oil sales and delivery contracts for oil volumes we plan to produce from the Niobrara in Colorado.

The table below summarizes the future production volumes to be sold under one of these contracts as of July 1, 2014 at a price equal to NYMEX less a fixed differential of $4.75 per Bbl. If we are unable to deliver the production volumes specified in this contract, the fixed differential will increase proportionately.

Commodity	Period	Average Daily Volume (Bbl per day)
Crude oil	01/2015 to 12/2015	25,000
Crude oil	01/2016 to 12/2016	30,000
Crude oil	01/2017 to 12/2017	35,000
Crude oil	01/2018 to 12/2018	40,000
Crude oil	01/2019 to 12/2019	45,000

Table of Contents

The table below summarizes the future production volumes to be sold under the second contract as of July 1, 2014 at a price equal to NYMEX less certain fixed differentials depending on the delivery methods specified in the contract:

Commodity	Period	Average Daily Volume (Bbl per day)
Crude oil	07/2015 to 12/2015	20,000
Crude oil	01/2016 to 12/2016	20,000
Crude oil	01/2017 to 12/2017	20,000
Crude oil	01/2018 to 12/2018	20,000
Crude oil	01/2019 to 12/2019	20,000
Crude oil	01/2020 to 06/2020	20,000

Fixed-price Natural Gas Contracts. We have various fixed-price gas sales contracts with end users for a portion of the natural gas we produce in Colorado and Utah. Our future production volumes projected to be sold under these fixed-price contracts as of July 1, 2014 are summarized below:

Commodity	Period	Average Daily Volume (MMBtu per day)	Weighted Average Price Per MMBtu
Natural gas	07/2014 to 09/2014	11,000	$5.49
Natural gas	10/2014 to 12/2014	11,000	$5.49

Commodity Derivatives Conveyed to Whiting USA Trust II. In connection with our conveyance in March 2012 of a term net profits interest to Whiting USA Trust II ("Trust II"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 241 MBbl of crude oil in 2014, have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. This results in third-party public holders of Trust II units receiving 90%, while we retain 10%, of the future economic results of such hedges. No additional hedges are allowed to be placed on Trust II assets.

The table below summarizes all of the outstanding costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Trust II (of which we retain 10% of the future economic results and third-party public holders of Trust II units receive 90% of the future economic results):

Conveyed to Whiting USA Trust II

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	NYMEX Floor/Ceiling

Collars	Crude oil	07/2014 to 09/2014	40,600	\$80.00/\$122.50
	Crude oil	10/2014 to 12/2014	39,700	\$80.00/\$122.50

Embedded Commodity Derivative Contracts—The price we pay for oil field products and services significantly impacts our profitability, reserve estimates, access to capital and future growth rate. Typically, as prices for oil and natural gas increase, so do all associated costs. In May 2011, we entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in our EOR project at the North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices, in order to reduce our exposure to paying higher than the market rates for CO2 in a climate of declining oil prices. We have determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and we have therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. This embedded commodity derivative contract has not been designated as a hedge, and therefore all changes in fair value since inception have been recorded immediately to earnings. The price per Mcf of CO2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. For this embedded commodity derivative contract, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of June 30, 2014 would cause a decrease or increase, respectively, of $10.0 million in our commodity derivative loss.

Table of Contents

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of June 30, 2014. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of June 30, 2014 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended June 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) issued an updated version of its Internal Control – Integrated Framework (the “2013 Framework”). Originally issued in 1992 (the “1992 Framework”), the framework helps organizations design, implement and evaluate the effectiveness of internal control concepts and simplify their use and application. The 1992 Framework remains available during the transition period, which extends to December 15, 2014, after which time COSO will consider it as superseded by the 2013 Framework. As of June 30, 2014, the Company continues to utilize the 1992 Framework during its transition to the 2013 Framework by the end of 2014.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management's opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10 K for the fiscal year ended December 31, 2013. The following are material updates to such risk factors.

Failure to complete the Kodiak Acquisition could negatively affect our share price, future business and financial results.

Completion of the Kodiak Acquisition is not assured and is subject to risks, including the risks that approval of the transaction by our stockholders and the shareholders of Kodiak, by the applicable court or by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the Kodiak Acquisition is not completed, our ongoing business and financial results may be adversely affected and we will be subject to several risks, including:

- having to pay certain significant transaction costs relating to the Kodiak Acquisition without receiving the benefits of the Kodiak Acquisition;
- potentially having to reimburse up to $10.0 million of Kodiak's expenses if our stockholder approval is not obtained or a termination fee of $130.0 million plus reimbursement of up to $10.0 million of Kodiak's expenses in other specific circumstances, including without limitation, a change in our board of directors' recommendation to our stockholders or termination to accept an alternative acquisition proposal;
- our share price may decline to the extent that the current market prices reflect an assumption by the market that the Kodiak Acquisition will be completed; and
- we may be subject to litigation related to any failure to complete the Kodiak Acquisition.

We will incur substantial transaction fees and costs in connection with the Kodiak Acquisition.

We expect to incur a significant amount of non-recurring expenses in connection with the Kodiak Acquisition. Additional unanticipated costs may be incurred in the course of the integration of our businesses and the business of Kodiak. We cannot be certain that the elimination of duplicative costs or the realization of other efficiencies related to the integration of the two businesses will offset the transaction and integration costs in the near term, or at all.

We and Kodiak may be unable to obtain the court and regulatory approvals required to complete the Kodiak Acquisition or, in order to do so, we and Kodiak may be required to comply with material restrictions or conditions that may negatively affect the combined company after the Kodiak Acquisition is completed or cause us to abandon the Kodiak Acquisition. Failure to complete the Kodiak Acquisition could negatively affect our future business and financial results.

Completion of the Kodiak Acquisition is contingent upon, among other things, the receipt of certain court and regulatory approvals, including the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act"). We and Kodiak can provide no assurance that all required court and regulatory approvals will be obtained or that the approvals or consents will not contain terms, conditions or restrictions that would be detrimental to the combined company after completion of the Kodiak Acquisition.

Delays in completing the Kodiak Acquisition may substantially reduce the expected benefits of the Kodiak Acquisition.

Satisfying the conditions to, and completion of, the Kodiak Acquisition may take longer than, and could cost more than, we expect. Any delay in completing or any additional conditions imposed in order to complete the Kodiak Acquisition may materially adversely affect the synergies and other benefits that we expect to achieve from the Kodiak Acquisition and the integration of our businesses. In addition, we and Kodiak each have the right to terminate the Kodiak Acquisition agreement if the Kodiak Acquisition is not completed by January 9, 2015, except that such date may be extended to March 10, 2015 if the only unsatisfied conditions to the completion of the Kodiak Acquisition is the expiration or termination of the waiting period under the HSR Act.

Stockholder litigation against Kodiak and/or us could result in an injunction preventing completion of the Kodiak Acquisition, the payment of damages in the event the Kodiak Acquisition is completed, and/or may adversely affect the combined company's business, financial condition or results of operations following the Kodiak Acquisition.

Transactions such as the Kodiak Acquisition are often subject to lawsuits by stockholders. In connection with the Kodiak Acquisition, four purported class action lawsuits have been filed on behalf of Kodiak shareholders in the United States District Court for the District of Colorado: Quigley and Koelling v. Whiting Petroleum Corporation, et al., Case No. 1:14-cv-02023, filed July 22, 2014; Fioravanti v. Krysiak, et al., Case No. 1:14-cv-02037, filed July 23, 2014; Wilkinson v. Whiting Petroleum Corporation, et al., Case No. 1:14-cv-2074, filed July 25, 2014; and Goldsmith v. Krysiak et al., Case No. 1:14-cv-2098, filed July 29, 2014. It is possible that other related suits could subsequently be filed.

The allegations in the four lawsuits are similar. They purport to be brought as class actions on behalf of all shareholders of Kodiak. The complaints name as defendants the Kodiak board of directors and us and list Kodiak as a nominal party. The complaints allege that the Kodiak board of directors breached its fiduciary duties to Kodiak shareholders by, among other things, failing to engage in a fair sale process before approving the Kodiak Acquisition and to maximize shareholder value in connection with the Kodiak Acquisition. Specifically, the complaints allege that the Kodiak board of directors undervalued Kodiak in connection with the Kodiak Acquisition and that the Kodiak board of directors agreed to certain deal protection mechanisms that precluded Kodiak from obtaining competing offers. The four complaints also allege that we aided and abetted the Kodiak board of director’s alleged breaches of fiduciary duties. The complaints seek, among other things, injunctive relief preventing the closing of the Kodiak Acquisition, rescission of the Kodiak Acquisition or an award of rescissory damages to the purported class in the event that the Kodiak Acquisition is consummated, and damages, including counsel fees and expenses.

One of the conditions to the closing of the Kodiak Acquisition is that no law, order, injunction or judgment shall have been enacted or issued by any government entity that has the effect of making illegal or otherwise prohibiting the consummation of the Kodiak Acquisition. Consequently, if any lawsuit is successful in obtaining an injunction prohibiting us or Kodiak from consummating the Kodiak Acquisition on the agreed upon terms, the injunction may prevent the Kodiak Acquisition from being completed within the expected timeframe, or at all. Furthermore, if the Kodiak Acquisition is prevented or delayed, the lawsuits could result in substantial costs, including any costs associated with the indemnification of directors. The defense or settlement of any lawsuit or claim that remains unresolved at the time the Kodiak Acquisition is completed may adversely affect the combined company's business, financial condition or results of operations.

We will be subject to various uncertainties and contractual restrictions while the Kodiak Acquisition is pending that could adversely affect our financial results.

Uncertainty about the effect of the Kodiak Acquisition on employees, service providers, suppliers and customers may have an adverse effect on us. These uncertainties may impair our ability to attract, retain and motivate key personnel until the Kodiak Acquisition is completed and for a period of time thereafter, and could cause service providers, customers, suppliers and others who deal with us to seek to change existing business relationships with us. Employee retention and recruitment may be particularly challenging prior to completion of the Kodiak Acquisition, as employees and prospective employees may experience uncertainty about their future roles with the combined company.

The pursuit of the Kodiak Acquisition and the preparation for the integration of the two companies may place a significant burden on management and internal resources. Any significant diversion of management’s attention away from ongoing business and any difficulties encountered in the transition and integration process could affect our financial results or the financial results of the combined company.

In addition, the Kodiak Acquisition agreement restricts us from taking certain specified actions while the Kodiak Acquisition is pending without first obtaining Kodiak's prior written consent. These restrictions may limit us from pursuing attractive business opportunities and making other changes to our business prior to completion of the Kodiak Acquisition or termination of the Kodiak Acquisition agreement.

We and Kodiak may experience difficulties in integrating our businesses, which could cause the combined company to fail to realize many of the anticipated potential benefits of the Kodiak Acquisition.

We and Kodiak entered into the arrangement agreement with the expectation that the arrangement will result in various benefits, including, among other things, operating efficiencies and cost savings. Achieving the anticipated benefits of the Kodiak Acquisition will depend in part upon whether our two companies integrate our businesses in an efficient and effective manner. Kodiak and us may not be able to accomplish this integration process successfully. The difficulties of combining the two companies' businesses potentially will include, among other things:

- the necessity of addressing possible differences incorporating cultures and management philosophies, and the integration of certain operations following the transaction will require the dedication of significant management resources, which may temporarily distract management's attention from the day-to-day business of the combined company; and
- any inability of our management to cause best practices to be applied to the combined company's businesses.

An inability to realize the full extent of the anticipated benefits of the transaction, as well as any delays encountered in the transition process, could have an adverse effect upon the revenues, level of expenses and operating results of the combined company, which may affect the value of the our common stock after the closing of the arrangement.

The market price of our common stock may decline in the future as a result of the Kodiak Acquisition.

The market price of our common stock may decline in the future as a result of the Kodiak Acquisition for a number of reasons, including the unsuccessful integration of Kodiak and us (including for the reasons set forth in the preceding risk factor) or our failure to achieve the perceived benefits of the Kodiak Acquisition, including financial and operating results, as rapidly as or to the extent anticipated by financial or industry analysts. These factors are, to some extent, beyond our control.

Our current stockholders will have a reduced ownership and voting interest after the Kodiak Acquisition.

As a result of the stock we expect to issue as part of the Kodiak Acquisition, our current stockholders and Kodiak shareholders are expected to hold approximately 71% and 29%, respectively, of the combined company's outstanding common stock immediately following completion of the Kodiak Acquisition. Our stockholders currently have the right to vote for directors and on other matters affecting our company. When the Kodiak Acquisition occurs, each of our stockholders will remain a holder of our common stock with a percentage ownership of the combined company that will be smaller than the shareholder's percentage of our common stock prior to the Kodiak Acquisition. As a result of this reduced ownership percentage, our stockholders will have less voting power in the combined company than they now have with respect to us.

Item 6. Exhibits

The exhibits listed in the accompanying index to exhibits are filed as part of this Quarterly Report on Form 10 Q.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 31st day of July, 2014.

WHITING PETROLEUM CORPORATION

By /s/ James J. Volker
James J. Volker
Chairman, President and Chief Executive Officer

By /s/ Michael J. Stevens
Michael J. Stevens
Vice President and Chief Financial Officer

By /s/ Brent P. Jensen
Brent P. Jensen
Controller and Treasurer

Table of Contents

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(2.1)	Arrangement Agreement, dated as of July 13, 2014, by and among Whiting Petroleum Corporation, 1007695 B.C. Ltd. and Kodiak Oil & Gas Corp. [Incorporated by reference to Exhibit 2.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated July 13, 2014 (File No. 001-31899)].
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(101)	The following materials from Whiting Petroleum Corporation's Quarterly Report on Form 10 Q for the quarter ended June 30, 2014 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of June 30, 2014 and December 31, 2013, (ii) the Consolidated Statements of Income for the Three and Six Months Ended June 30, 2014 and 2013, (iii) the Consolidated Statements of Comprehensive Income for the Three and Six Months Ended June 30, 2014 and 2013, (iv) the Consolidated Statements of Cash Flows for the Six Months Ended June 30, 2014 and 2013, (v) the Consolidated Statements of Equity for the Six Months Ended June 30, 2014 and 2013 and (vi) Notes to Consolidated Financial Statements.